Southern Reporting, Inc.

Transcript of
Ex Parte Briefing

10/23/2018

Avoided Cost, Resource Planning and Energy Storage in an Era of Low-Cost Solar
ND-2018-23-E

COPY

Southern Reporting, Inc.
Phone: 803.749.8100
Fax: 803.749.9991
Email: Depos@southernreporting.net

Before the Public Service Commission of South Carolina
Columbia, South Carolina

October 23, 2018 2:00 p.m.

Allowable Ex Parte Briefing ND-2018-23-E
South Carolina Solar Business Alliance, Incorporated - Request for an Allowable Ex Parte Briefing Regarding Avoided Cost, Resource Planning and Energy Storage in an Era of Low-Cost Solar

TRANSCRIPT OF ALLOWABLE PROCEEDINGS EX PARTE BRIEFING

HEARING BEFORE: Vice Chairman Elliott F. Elam; Commissioner G. O'Neal Hamilton; Commissioner Thomas J. "Tom" Ervin; Commissioner Justin T. Williams;

ADVISOR TO COMMISSION: Joseph Melchers, Esq.
Legal Advisory Staff

APPEARANCES

Richard L. Whitt, Esq., representing South Carolina Solar Business Alliance, LLC; together with Hamilton Davis, Esq. (Southern Current, LLC), Steven J. Levitas, Esq. (Cypress Creek Renewables, LLC), and Ronald DiFelice, Ph.D. (Energy Intelligence Partners).

Jeffrey M. Nelson, Esq., representing the South Carolina Office of Regulatory Staff.

REPORTED BY:
Kathleen R. Tackett, CVR-M

INDEX

Please note the following inclusions/attachments to the record:

PowerPoint Presentation Slides (PDF) re: "Avoided Cost, Resource Planning, & Energy Storage."

PowerPoint Presentation Slides (PDF) re: "Energy Storage - SC Ex Parte Briefing."

PROCEEDINGS

VICE CHAIRMAN ELAM: Good afternoon. Welcome to this allowable ex parte. Call it to order and ask our counsel, Mr. Melchers, to read the docket.

MR. MELCHERS: Thank you, Mr. Acting Chairman and Commissioners. We're here pursuant to notice of request for allowable ex parte communication briefing. The person requesting the briefing is Richard Whitt, and he has brought a number of folks to help us with the briefing, from Southern Current, Cypress Creek Renewables, and Energy Intelligence Partners. It is scheduled for today, October 23rd, at 2 p.m., here in the Commission hearing room, and our subject matter to be discussed today is avoided cost, resource planning, and energy storage in an era of low-cost solar. Thank you, sir.

VICE CHAIRMAN ELAM: Okay. We'll start with appearances. I guess we'll go with ORS first and ask if they could also follow that up with going over the ground rules.

MR. NELSON: Thank you, Mr. Chairman. I'm Jeff Nelson on behalf of the

Office of Regulatory Staff, and I'll -- as it is our custom, I'm going to do a little introduction here just to kind of set the ground rules so that everybody knows how things work today.

My name's Jeff Nelson. I'm the chief counsel for the Office of Regulatory Staff, and I am here as the designee of the executive director of ORS, who is required under South Carolina law to certify the proceedings in front of the Commission today. This is allowable ex parte, as Mr. Melchers has said. It's presented by the South Carolina Solar Business Alliance, and it's to be conducted in accordance with the provisions of South Carolina Code Annotated, Section 58-3-260C. As the ORS representative, it's my duty to certify the record of this proceeding to the chief clerk of the Public Service Commission -- that's Ms. Jocelyn Boyd -- within 72 hours of this briefing taking place.

The requirements, also, under the statute, are that, in part, the allowable ex parte needs to be confined to the subject matter that's been noticed in a public notice that was given today. And, again, the topic being avoided cost, resource planning, and energy in an era of low-cost solar. So both presenters and Commissioners, I'd ask you, please, remain on topic as best you can.

Under the provisions of 58-3-260, participants, commissioners, and commission staff are prohibited from requesting or giving "any commitment, predetermination, or prediction regarding any action that the Commission may take as to any ultimate or penultimate issue that is either before or is likely to come before the Commission." So, again, we ask that the presenters not ask for opinions or for decisions by the Commission and, of course, that the commissioners refrain from doing so.

Finally, everyone here in attendance today has to read and sign the form that you should've been given when you came in today. Please actually read the form. Please make sure you sign it, and please make sure that it's turned in before you leave today. That's another thing that has to be certified, is actually the attendance list, balancing against those signed documents.

So that's all I have, Mr. Melchers. Thank you. Mr. Chairman.

VICE CHAIRMAN ELAM: Thank you, Mr. Nelson. Mr. Whitt?

MR. WHITT: Thank you, Mr. Vice Chairman, other commissioners, and Mr. Melchers. We want to thank you for the opportunity to appear here today for the South Carolina Solar Business Alliance. We appreciate your time. We know you're busy with the upcoming hearing. We also appreciate your staff who helped us put this together today. So we appreciate that, and, Mr. Vice Chairman, may I take a moment to introduce some of my clients that are here?

VICE CHAIRMAN ELAM: Please do.

MR. WHITT: Okay. We have Bret Sowers, who's the vice president of Southern Current, and he's also chairman of the SCSBA, is here. We have Patty Wright from Pine Gate Renewables. We have -- Andrew Berrier, from Pine Gate, is here, also. And we have Jarrett Branham of Alder Energy Systems. We have Steven Shirey of NCRE, and I don't know, did

Luke Rogers make it today? Luke, and Eric Panicco from Birdseye are here, and we appreciate them being here, also.

Before I call the panel, Mr. Vice Chairman, I want to say for the record the thing that we always say is that we have attorneys participating today, but they are participating as subject-matter experts, and they're not here to represent anyone today as attorneys, okay?

Well, thank you, Mr. Vice Chairman. We'd like to call Hamilton Davis of Southern Current, Steve Levitas of Cypress Creek, and Dr. Ronald DiFelice of Energy Intelligence Partners. And Hamilton Davis will start first.

VICE CHAIRMAN ELAM: Good afternoon, gentleman. Just start when you're ready.

MR. DAVIS: Good afternoon. Good to see most of our commissioners here today. Thank y'all for taking the time to listen to what we have to say. It's been a little while since I appeared before this Commission, so it's good to be back. I see two new faces. Commissioner Williams, Commissioner Ervin, congratulations on your appointment, and good to be talking with you today.

So, here at the outset, my job here is kind of prepare you guys for the presentations you're going to hear after me, so I'm going to lay a little bit of groundwork that, maybe, will help with what you hear later on. But what I would like to encourage is questions from you guys. We don't often get to appear. I think not often enough, have this opportunity to have a thoughtful discussion. Certainly, it's going to be partially a presentation, but I'd like for it to be a discussion as well. I know, within a contested case, it is filled with a lot of complicated issues and very smart technical experts, and it's not the type of discussion that we hope to bring you today. It's a little bit higher level and takes a bigger-picture perspective, trying to fit some of the pieces together that are critical to our business model and important to the folks of South Carolina and looking at it from that perspective.

So I want to start by just talking

about and pointing to some of the changes we've seen in the industry over the last decade. If you go back to 2009, especially in a state like South Carolina, you could definitely make the statement that solar maybe was a fringe technology. It was not playing a large role in our energy sector. That's changed dramatically over the last ten years. If you look at this from a -- from a cost perspective, go back to 2009, we've seen the cost per watt of solar above $7. That's dropped now, in 2018, to below $2 per watt. We've also seen installed capacity over that same timeline grow from a rate of less than a gigawatt a year to over 10 gigawatts per year, nationally.

Going back to 2017, over 40 percent of the installed capacity new energy in the United States last year was from solar power. We take a look at what's happened in the states around South Carolina. We see today that North Carolina is second in the nation for installed solar capacity, at 4.4 gigawatts, which translates into about $6.5 billion that has been invested in that state to bring those projects on line. Georgia is now tenth in installed capacity, with about 1.5 gigawatts, which translates into about $2 billion invested in that state to bring those projects on line. And, just recently, we've seen, in Virginia, Dominion Energy announced that they plan to develop over 3,000 megawatts of solar in just the next few years, which will put them on pace to enter into the top ten nationally for the rate at which solar's coming on.

Just for some comparison to South Carolina, today South Carolina is 18th in installed capacity with about 591 megawatts in the ground. That translates into about $840 million that have been invested into the state, and our projected growth is around Number 20, nationally.

Of course, with all of this investment comes jobs, and we can see that from this chart, where the industry has grown over the last ten years from less than 100,000 jobs, to over 250,000 nationally. So this is, indeed, a job of -- a growth sector in the economy.

I was very involved in 2013 to 2015. I think I -- I felt like I spent fully two years of my life working on Act 236, that you guys are very familiar with. That was a modest step forward on solar in South Carolina, but it was an important one, and I think it was a successful one. It got our state into a place where we had the experience, we had the exposure to think a bit more critically, more effectively, about how we really make this resource work in our state.

From an on-the-ground perspective, we have over 1,000 megawatts of executed PPAs now in South Carolina, which most of them -- most of which are in SCE&G territory. But, statewide, it's a little bit higher than that. We have over $5 billion of projects proposed in the state, in the development pipeline, in the utilities interconnection queues, which translate into $750 million in wages and $25 million a year in property-tax revenue. And, three short years later, after passing Act 236, I think you see a much more sophisticated industry at play here. I also think you see a much more complicated energy landscape in South Carolina.

So, as a result of that, whether you're talking about integrated resource planning or avoided cost or a myriad of other factors, there are hundreds of millions of dollars and billions of dollars on the line when we make decisions about how we're going to power the future of this state. Where is that going to come from, who's going to pay for it, and are those least-cost resources?

So I think the question that the solar industry is always looking to answer as we move into different markets is are we holding ourselves to best practices? Are we operating in an environment where the industry has appropriate standards in place so that we can go in and actually compete? So, whether it's cybersecurity or grid modernization, distributed energy resources, energy storage, integrated resource planning, there are literally a flood of other issues and considerations that lay ahead of us in the near future. There are billions of dollars that are going to be invested in this energy landscape in the state. Are those investments in the best interest of ratepayers? Are they in the best interest of South Carolina's economy?

We, as solar developers, are looking forward to an opportunity to compete and compete effectively. That requires regulatory rigor, transparency, accurate price signals so that we can compete, access to the grid. It requires a recognition of things like IRPs and avoided costs are intimately connected; you can't talk about one without talking about the other. And we believe that the Commission has fundamentally been empowered by the General Assembly to hold us, the solar industry, utilities, and anyone else that comes behind -- comes in front of you to best practices. The South Carolina laws create a framework to regulate, but you guys create the rules.

And, so, at the end of the day, we rely heavily on the Public Service Commission and regulators in every state we operate in to ensure that a fair opportunity exists to compete at a reasonable scale. And we think engendering more competition in this state is in the economic best interest of both ratepayers and the South Carolina economy.

And, so, to that end, I'm going to turn this over to Steve Levitas to talk a little more about what competition means to our industry and how we get there.

MR. LEVITAS: Thank you, Hamilton. And, thank you, Mr. Vice Chairman and members of the Commission. It's a pleasure to be back with you again today. I am Steve Levitas with Cypress Creek Renewables. I'm our senior vice president for regulatory affairs.

I've got a fairly, somewhat longish, prepared presentation, so I'd just like to encourage and invite you: If you would like to interrupt me at any time with questions, I'd be happy to entertain them as we go along.

So let me -- let me start by saying that, as we all know, the US economy is founded on free markets and competition. The one exception to this fundamental principal in our capitalist system is where natural monopolies exist, meaning that it doesn't make practical or economic sense to have multiple market participants. In these cases, it's essential that we have regulatory bodies like this Commission to set pricing and ensure that customers are protected from the potential abuse of monopoly power. If you take a look at this slide, you may recall, Commissioner Elam, when you noted that the Commission's regulation of utilities "attempts to replicate the conditions that a company in a competitive market would face." But I want to emphasize, and I suspect everyone in the room would agree, that the regulation of monopolists is a challenging and imperfect undertaking. Regulated monopolies, a necessary evil, I would say, in the case of true natural monopolies, should be the rare exception in our economic system. And free-market competition, I think we all believe, should be promoted wherever possible. That's why over the past several decades we've seen significant transition from regulated monopoly structures to competitive markets in sectors such as telecommunications and airline industries, and this has benefitted customers by unleashing innovation and dramatically lowering prices. In the electric industry, there's no question that transmission and distribution services remain a natural monopoly. Since no one would want to see competing systems of wires crisscrossing the landscape, we need to maintain our current system of assigned service territories with pricing regulated by state commissions inferred. In contrast, however, electric generation is not a natural monopoly, and there's no reason that we should allow monopoly utilities to be insulated from competitive pressure in providing generation services.

As a result of this fact, 13 states plus the District of Columbia have had deregulated generation markets for almost two decades, which are operating successfully today. As this slide illustrates, these markets have been substantially -- have seen substantially -- sorry. Thank you.

As this slide illustrates, these markets have seen substantially better results for customers than states with regulated monopoly-generation markets. I realize it's a little hard to see. I think you have hard copies in front of you, but, essentially, the green line, the bottom lines, are the customer-choice markets that show significantly better performance than the regulated markets. More states would have almost certainly joined the wave of deregulation in the 1990s and early 2000s had certain design flaws in the early programs and market practices, notably in California, not brought this trend to an abrupt halt. As I mentioned, though, the existing deregulated markets are functioning extremely well today.

Now, of equal importance, dramatic changes at the wholesale level over the past several decades have created significant competitive pressure in generation markets. Specifically, as you see here, much of the country is served by organized wholesale markets in which regular auctions for energy and capacity, together with open-access transmission tariffs, have created an efficient generation market based on competitive pricing. These markets are successfully meeting security and reliability requirements while delivering affordable, competitively-priced electricity to consumers.

There are three primary benefits to customers from competitive markets versus regulated monopolies. The biggest one is the same benefit that we see from competition throughout our economy: Competition drives prices down. It improves the quality of service for consumers as multiple sellers strive to innovate and achieve efficiencies or accept lower returns in order to offer the most attractive price and quality and to acquire and maintain market share.

The increased market access that renewable generation has experienced -- and Mr. Davis was highlighting this, as well -- over the past decade has helped drive prices down to the point that solar and wind are the cheapest sources of new energy on the market today, and you see those solar -- utility scale solar numbers circled in red up there on the upper corner of that slide.

Second, in regulated generation markets, customers typically are made to bear construction and operating risks. It's the rare occasion when regulated utilities are not allowed to recover from ratepayers most of the impact of construction delays and cost overruns or, for that matter, unexpected costs, such as coal-ash remediation. And regulated utilities typically continue to recover generation plant costs, regardless of their operating performance.

In other words, investor-owned utilities, or IOUs, are able to privatize profits for their shareholders and socialize risks by passing them on to ratepayers.

By contrast, where energy and capacity are provided by independent power producers, which I'll refer to as "IPPs," their investors, not the ratepayers, bear all of these risks.

Finally, a huge benefit of a competitive market is that it gives customers choice as to the type of product they buy and the seller they deal with. The electric-generation sector is one of the few in our economy where customers don't have that choice, even when they desperately want it.

In particular, a huge and growing number of private-sector companies, public and private institutions, and local governments have committed to procuring renewable energy, in many cases, having made 100 percent renewable pledges. I think there's something like 74 Fortune 500 companies that have gone 100 percent renewable. I think I saw that there are 88 local governments across the country that have made similar pledges.

Whether the state's regulatory framework supports that choice is an important factor in these companies' consideration when they decide where to locate or expand.

Now, similarly, among the general public, polling data from a range of credible sources shows a -- not sure why I'm a little trigger happy here -- this is a slide that shows polling data, and you'll see at the top 89 percent of the public favoring an increase in solar-farm deployment.

Now, in a regulated generation market like South Carolina's, these customers have no ready ability to meet these goals. Since they have to buy all their power from the utility, their energy profile will necessarily be the profile of the utility, which might be closer to 30 percent coal, 35 percent natural gas, 30 percent nuclear, and, say, just 5 percent renewables. As I said, it's critically important that mechanisms be in place to allow customers to meet their requirements and preferences for a hundred percent clean energy, or they simply may decide not to make further investments in the state.

Now, the last time I was here, I spoke to you about Senate Bill 987, which was introduced in the last session, which was a mechanism to address exactly this issue of providing commercial and industrial customers with access to renewable energy in the context of today's regulated generation market. So I don't plan to revisit that today, unless you may have any questions.

But I will say that effective competition from solar-independent power producers is especially important here in South Carolina, because the generation options are limited. The latest South Carolina nuclear experiment at VC Summer was not successful, and there's little prospect that further nuclear-project development will be undertaken. New coal is not a viable option for our use today due to its emissions profile. The availability of cleaner, cheaper alternatives, like renewables and gas, and, frankly, for the reasons I've said, a huge portion of the customers simply don't want it.

Same time, a diverse-resource portfolio is critical to mitigating risks and cost effectively meeting system demands. Overcommitting to natural gas, in addition to its environmental impacts, will subject ratepayers to potentially disastrous risks of fuel-price increases and volatility. We were recently reminded of that volatility when the market price for natural gas unexpectedly shot up 10 percent during the past few weeks, and no one can say for sure how far prices will move back down or when they might suddenly escalate again.

It is noted utility-scale solar is the least-cost option in the market today, and IPPs, importantly, can deliver solar at a lower cost than IOUs. IPP Solar Development has the potential to bring billions of dollars, as Mr. Davis said, in investment to the state that will directly benefit some of South Carolina's poorest and most rural counties.

Now, with that background, let me say, I don't mention any of that and the importance of competition to suggest to you that South Carolina should deregulate its electric-generation sector.

Rather, my purpose is to talk with you about some of the ways to better capture the benefits of competition in customer choice in the context of continued -- a continued regulated-monopoly regime.

The key thing is that, to capture the benefits of a competitive market for consumers, it's essential that there be more than one player in the market. It's essential that IPPs, like SCSBA's members, have meaningful nondiscriminatory access to the generation market, and I'll talk about some ways that that can occur.

For a start, federal law requires that we have such access, specifically under the Public Utility Regulatory Policies Act, or

PURPA. As you know, PURPA requires electric utilities to purchase the output of certain IPPs, called "qualifying facilities," or "QFs," at the cost that the utility would otherwise incur to generate or purchase such energy and capacity.

I know you're familiar with PURPA, and my intention today is not to discuss its requirements and benefits in detail, but they are briefly summarized in these slides, which you -- in this slide, which you have.

But, in connection with my discussion of the importance of competitive pressure on monopoly pricing, I do want to say that it's important that state commissions implement PURPA in a manner that does, in fact, give QFs meaningful market access.

The most important conditions for such access are these: First of all, a properly-calculated avoided-cost rate that accurately reflects the utility's true avoided costs.

Second, a long-term fixed-price contract that gives QFs a reasonable opportunity to attract capital as FERC requires.

And, finally, nondiscriminatory

interconnection access to the utility's transmission and distribution system, a subject that we have addressed in prior ex parte briefings before you.

COMMISSIONER ERVIN: Steve, may I interrupt you --

MR. LEVITAS: Yes.

COMMISSIONER ERVIN: -- for a question?

MR. LEVITAS: Yes. Absolutely.

COMMISSIONER ERVIN: When you say long-term fixed-price contracts, is there a best-practices kind of scale where it'd be like 20 years or something less? More or less?

MR. LEVITAS: Thank you for that question. It varies a lot across the country. FERC has not dictated a one-size-fits-all. It has, as I said, said that the contracts have to be of sufficient length, and the exact words are "to give the QF a reasonable opportunity to attract capital." So that's going to vary by market, depending on the price and land cost and other factors -- jurisdiction-specific factors.

I can tell you that -- and I was about to mention this -- from our standpoint, there are many states in the country that we don't believe have complied with this requirement and that allow utilities to offer very short contracts, variable-price contracts, but there are many states around the country that do prescribe longer-term contracts.

Michigan just approved a 20-year contract in the last year or -- well, the final order just went into effect the other day; Washington State, I believe, is looking at 15 years; Minnesota, 20 years; Montana, which has not been a real friend to QFs, is at 15 years, down from 25, but there are certainly shorter places.

But I think one of the things that -- there's discussion at the Federal level about possible changes to PURPA, and one of the ones that I think is most important is to try to get some kind of standardization, rebuttable presumption, because we wind up litigating and fighting about it, and it ought to be something that has a little more uniformity.

COMMISSIONER ERVIN: And I understand that, in North Carolina, our neighboring state has adopted a statutory scheme that is about to be implemented or -- and since some of the territory bleeds into our state -- are you familiar with that scheme? Are you going to address that for us?

MR. LEVITAS: I'll say a little bit about that. I wasn't going to say anything about it in the context of the contract length, but I will tell you this -- and I was intimately involved with the legislation last year in North Carolina -- that legislation reflected a conscious attempt, after years of successful PURPA implementation that stimulated many, many gigawatts of IPP solar development, to move away from that, just to a different regime, which I'll talk about. And the five-year PPA length that was adopted by the legislature in North Carolina was specifically adopted for the purpose of shutting down PURPA, so that the migration to competitive solicitation would be successful.

So I don't think you can look at it as an example where a state is in the earlier stages of PURPA implementation and say, "Oh, well, five years has been agreed to be a workable solution." It was consciously intended not to allow contracts to occur under PURPA.

COMMISSIONER ERVIN: That answers my question. Thank you.

MR. LEVITAS: So, as I was saying, despite clear mandates from Congress and FERC, we have unfortunately seen, across many states in the country, a failure to comply with PURPA and to implement it as intended and, particularly, around this issue of contract length.

And, on that point, I would say that it's just important to remember that no utility would ever build major-generation infrastructure without long-term stability as to cost recovery. And that includes utility affiliates.

This is a slide relating to Duke Renewables, Duke Energy's non-regulated affiliate, that is effectively a competitor of ours in many markets. It's one of the leading renewable-energy developers in the country, and we're not aware that Duke Renewables has ever entered into a -- our purchase agreement of less than 15 years, and you see that the average is over 18 years.

Now, I try to have honest conversations and hear what other folks have to say about PURPA, and one common argument that you hear is that long-term, fixed-price contracts could turn out to be inaccurate, and, if they're too high -- if the projections or forecasts are too high, the ratepayers could suffer.

And the response that I'd make to that is that's exactly the same risk that customers face every time a regulatory commission like this one approves long-term cost recovery for a utility's generation asset, and, you know, unfortunately, here in South Carolina, we're all too familiar with that phenomenon.

And the other thing that I think it's really important to know -- and I talked about it earlier -- is the risk allocation; it's really important. When IPP transactions occur, there are no risks on ratepayers if things go bad. If we don't perform, if our costs are too high, we bear all those risks. Our investors don't get any money. There's no opportunity to come to you and say, "Things didn't work out well. Will you pay us -- let us get paid anyway?" and make the customers eat the cost of something that delivers no value to them.

Now, another common concern about PURPA is that it requires utilities to purchase the output of facilities that the utilities say they don't want or need or that may present operational challenges. I have responses to those concerns.

The first thing that I would say is PURPA doesn't actually require a utility to pay a QF for a capacity that the utility doesn't need. So there's the energy component of what it costs and the capacity component. It's very clear, if the utility doesn't need capacity, doesn't have need for any new plants, they don't pay us for capacity.

With respect to energy, utilities that don't -- that have all the capacity they need almost always have a need for energy. If you think about what does that mean, a regulated utility serves its existing load largely by operating its existing fleet, which involves costs for fuel, for operations, for maintenance; that's energy. They do that every day, and they have a need to do that every day to serve their load. So PURPA simply gives IPPs the opportunity to meet that need if we can do so at comparable costs.

The operational issues only come into play when there is a high degree of renewable penetration, and certainly Duke made that case in North Carolina. I think that was influential. We didn't necessarily agree with all of it, but it was influential with our commission because we had had so much renewable penetration come on so fast. But we would like to see the utilities put their considerable talent to bear in solving these problems of integrating renewables that are so much in demand and not just flagging the problems.

So I think these concerns about PURPA are overstated, but I really wanted -- kind of the heart of my thoughts that I want to share with you today is about a partial substitute for PURPA that is another way to provide benefits of competition in a regulated market. So that's what I'm really here to talk about.

PURPA is what we've had to date, and as I said, it is specifically designed to provide competitive pressure in a regulated market. But there's an alternative. And that is a meaningful, inclusive, and technically sound, integrated resource planning process and a resource planning process that is combined with a properly designed and fairly administered competitive solicitation process, so a IRP RFP.

This type of procurement regime, which has been successfully deployed in Colorado, is very close to what's been recently proposed by NARUC, your national association, as an alternative to PURPA. This is just a cover page from the proposal that they released a week and a half ago, and I'm headed from here to a conference in Arizona to respond to this report and the authors. It should be an interesting discussion.

So, as I said, NARUC is proposing a move toward a IRP RFP model, but it's really important to recognize that, in regulated markets, the kind of solicitations NARUC proposes have only been applied to the procurement of new resources. So this model works really well if you're saying, "We need

500 megawatts of new capacity. Let's go into the market and figure out how to get it in the most cost-effective way." But in the absence of a structured wholesale market, it's really difficult, if not impossible, to imagine how utilities would procure all of their energy needs on a competitive basis. I'm not aware that those types of procurements are going on anywhere in the country in regulated markets.

I mentioned the Colorado model. It has shown how competitive procurement can lower costs for ratepayers. This slide's a little hard to follow, but Xcel in Colorado put out an all-resource bid in 2017 to replace 450 megawatts of retiring coal capacity. Wind, solar, and storage from IPPs emerged as the best and most cost-effective options, and the prices were extremely low.

(Indicating.) I seem to hit this twice every time. Maybe I'll get it figured out before we're done.

In 2016, the Michigan legislature enacted a rigorous new IRP process under which the first IRP was recently filed by Consumers Energy. We're heavily involved in that proceeding, and interestingly, Consumers proposes to accelerate coal plant retirements, do no new gas plant construction, increase the use of demand-side management and energy efficiency, and procure around 6 gigawatts of competitively procured solar resources. So there's certainly some things about the proposal that we think need some work, but that basic framework, again, the IRP used to define what the need is, and the commission there will complete that proceeding in the late spring of next year. And then, just as in Colorado, it's that IRP that drives the procurement and what gets built.

Now, you asked about House Bill 589 passed by North Carolina's General Assembly last year. As I said, that was specifically designed to migrate the state away from its longstanding approach to PURPA implementation to an independently administered competitive procurement regime. In that case, the legislature, rather than going through a IRP process at the front end, directed Duke Energy to competitively procure more than 2600 megawatts of new renewable resources. This was on top of what was assumed to be a baseline of 3500 megawatts that would be deployed prior to this RFP process. And then, for the commission subsequent to that, through an IRP to determine what need would exist beyond that initial addition of 2600 megawatts.

It's been a really interesting learning process in North Carolina. There's a lot that we can share from other states that can help guide both future procurements in North Carolina and elsewhere.

This IRP RFP model, in my opinion, is a great improvement over what we have typically seen in most Southeastern states where utilities have been able to obtain commission approval for major generation investments without being required, first of all, to go through an open, transparent, and participatory resource-planning process that determines and drives exactly what type and capacity resources get built, and then following on to that, to competitively bid generation procurement with open access to that bidding process for all participants.

As I imagine you know, the South Carolina State Energy Plan, developed under the guidance of ORS's energy office, has identified best practices for utility-integrated resource planning as a top priority for South Carolina. I have another slide that's a little hard to read here, but these practices include utilities holding public engagement sessions to discuss changes to its IRP and gather feedback; analyzing multiple resource portfolios with a range of demand-side and supply-side options; conducting multiple sensitivity analyses that consider uncertainty around factors like fuel costs and load growth; and evaluating retirement options for existing assets.

My personal view is that a monopoly utility should never be allowed to build a generation resource unless two conditions have been met: First, the need for the quantity and the type of additional capacity needs to have been determined by the commission through a rigorous, inclusive, and transparent process; second, no utility should be allowed to build any new resources itself unless it has prevailed in an inclusive, properly designed, and fairly and independently administered competitive process that is open to all market participants.

Now, I've heard questions or concerns expressed about how the introduction of these competitive pressures on the generation side may affect the economic stability of IOUs, and that certainly merits consideration. First of all, as I've said, the IOUs will continue to own and operate their transmission and distribution businesses the way they always have. Even where operation of the transmission system is placed in the hands of an independent system operator, this T&D transmission and distribution remains a very healthy, sustainable, and expanding business proposition for IOUs. There are billions of dollars of investment needed and planned and discussed with respect to grid improvements that provide substantial opportunities for earnings and profitability for utilities.

There's also a good deal of discussion going on about the so-called "utility business model of the future," including alternative models in which utilities are not compensated based on how much they build or sell, but on performance standards and the delivery of services to the public. And I think these bear considerations here and elsewhere, but I certainly agree that, as long as utilities continue to play a role in generation and specifically in managing -- a balancing authority area to ensure that we have system reliability, they should absolutely be compensated for doing so.

I also believe that competition from IPPs should not create stranded assets for IOUs and that they should continue to be fairly compensated for prudent investments that they've made in the past. But the decisions about the proper mix of new generation resources should be driven by sound resource planning, competitive pricing, and customer interests, not by shareholder interests.

Got one more slide? Maybe not.

So let me just conclude by saying thank you, again, for the opportunity to be here. These topics are all very much connected. The issue of the need for competitive pressure, the potential to do that through a more robust and rigorous planning process, leading to a fairly administered, competitive solicitation process, coupled with more robust and appropriate implementation of PURPA -- because the competitive solicitation model that I outlined, as I said, doesn't get you all the way there. It helps solve the approach on how we procure new resources, but the new resources are the tail of the dog. That may be 10 percent of the way in which -- of the way in which 10 percent of the existing load is met, so we have to have a mechanism like PURPA to continue to place competitive pressure on how the utilities' ongoing energy needs are met.

But I'll stop there. I don't know if you want to wait and hold questions till all of us are done, but I'll hand things over to Dr. DiFelice.

DR. DIFELICE: Thank you, Mr. Levitas. Vice Chairman, thank you for having me. Commissioners, it's good to be here. My name's Ron DiFelice, and I've got 10 minutes to educate you all on a very complex topic, and that is energy storage. And that's an industry that I've been a part of for about 17 years now in various capacities, pardon the pun, and in the last five years in particular, through my consulting firm Energy Intelligence Partners, we've spent a lot of time with utilities, Fortune 500 companies, and others trying to help them understand the emerging opportunities that energy storage presents for the grid.

And so, to give you the message of why this time is different for energy storage and how its time has arrived, we need to kind of look back and see what people have expected from energy storage for the past five to ten years.

And so this chart here -- and it may be one that you've seen before -- it's got "energy storage duration" of the asset on the x-axis, and it's got all the different buckets of services that energy storage can provide to the grid on the y. And you can see that energy storage can provide a wide range of benefits for the grid everywhere from bulk energy to T&D, renewables integration, and for consumers' demand-charge management, so behind-the-meter energy storage is a great asset for that.

So this has all been known and talked about for a long time, so what's different? What's changed? What you're looking at here is a chart from Bloomberg New Energy Finance that shows the decline in pricing for lithium ion battery cells measured in dollars per kilowatt hour. And you can see, from 2010 to this year, the drop has been tremendous, about 80 percent.

A little known fact is it's being driven by the EV markets. So billions are being invested right now into electric vehicles, and there are hundreds of gigawatt hours of capacity being built around the world right now to supply the budding EV market. The stationary energy storage market is going to benefit from all that investment and the price declines that we are seeing.

I also want to point out that there is a magic threshold here of $100 per kWh for energy storage where most experts predict the markets that I've shown on the previous slide will be dominated with -- by energy storage. Bloomberg projects that to be out in 2025, and this is a report from this year. Tesla has stated publicly that they will meet that threshold next year. And we are also very bullish that we are going to see pricing come down faster than predicted. And this is going to have big implications for where and how energy storage is deployed.

So you get a idea of this not being a localized market phenomenon, I wanted to share with you some slides from the Energy Information Administration. So what you're looking at is a chart from 2012 that shows energy storage deployments across the country. The size of the data points are indicative of the megawatts deployed. And if you fast-forward six years and look at that map, you can see the widescale adoption across the country. So we're not just talking about states like California and Hawaii. Energy storage makes sense in a lot of markets today, and it's going to make sense in a lot more markets in the next couple of years.

To further drive home the point that this is coming to the South, I want to draw your attention to this headline, which is from Duke Energy just this month, which touts their allocation of about $500 million to go into energy storage investment across the Carolinas.

The backdrop of this -- this graphic is a chart from Greentech Media. They do a nice job of tracking the deployments over time by year, and they also break it up by application. So you've got residential and C&I, which are behind the meter, and then you've got utility scale, which we call "front of the meter," and it's going to be dominated by front-of-the-meter utility scale. They're projecting 1 gigawatt deployed in 2019, and that's going to double in 2020. And so this year -- between this year and next year, we're talking about 5X what was deployed in 2016, so we're seeing tremendous growth in lithium-ion battery deployment.

What are the utilities using it for? In unregulated markets like PJM, energy storage has been used for several years now for frequency regulation services, but it's not just for ancillary services. This is a simple example of how energy storage can be used for time-shifting in places like the Southeast.

And so I think everyone knows that electrons delivered during the peak period for a utility are the most expensive electrons to generate and deliver. So the benefit of energy storage, when coupled with renewables, is you can charge the batteries with the solar or wind when you need it and then deploy them specifically into your peak periods. And this study, which was based on 2011 data, just came out in 2018 from the National Renewable Energy Lab, and it showed the impact on the state of California of over 4 gigawatts of storage, and you can see the variability during that 24-hour period shrinks greatly with energy storage, which is exactly what the utility wants to see.

You may have heard the word, or the term, "benefit stacking" in relation to energy storage, and what that means is using the storage asset for more than one thing at different times. It's a great idea on paper. It doesn't work quite yet in the real world with too many applications, because the lifetime of the battery is greatly affected if you do that and try to do too much with it.

I'm not talking about benefit stacking with this slide. I'm talking about if a storage asset is deployed just for time-shifting, so for one application. A grid is going to see all these other ancillary benefits because storage is deployed in that way. So from T&D deferral, your power quality goes up. Your heat rate goes down on that system, your air-emissions benefits are obvious, and your pricing risk -- your fuel pricing risk -- you don't have to deal with that as opposed to peaker plants.

And so this graphic -- this pie chart here in the bottom right is from PJM, and it shows -- it basically deconstructs what's in a kilowatt hour delivered, cost-wise, and so that's going to vary from market to market, and South Carolina's is going to look different, but the point is: Energy storage is going to decrease the cost in every one of those slices of the pie because it's such a versatile tool.

So those are my comments about energy storage. I'm happy to take questions, but the -- again, the point that I wanted to leave you with is it's not something that's coming in five years or ten years. Energy storage is here; the pricing is only going to get better; and it's -- we think in the next five to ten years it's going to impact every aspect of how a utility generates, transmits, distributes energy -- its energy. Thank you for your time.

VICE CHAIRMAN ELAM: Thank you. Commissioners? Questions? Go ahead, Commissioner Hamilton.

COMMISSIONER HAMILTON: Thank you, Mr. Chairman. I have one question. We -- in the points that you just made, Mr. DiFelice, and we've talked about it before, about baseload generation from solar and battery storage. Where are we now?

DR. DIFELICE: Is that directed to me?

COMMISSIONER HAMILTON: Yes, sir.

DR. DIFELICE: So we very much look at solar plus storage as a capacity asset. So when you add storage, you can deploy it when you need it, and that's very different than a renewable asset without storage, of course. So there's an energy component and an energy value to storage and there's also a capacity value to storage, just like you have with a peaker.

COMMISSIONER HAMILTON: Would either of you gentlemen have anything to add?

MR. DAVIS: I think I'll just add, Commissioner Hamilton, that he way we think about energy portfolio is diversity, and so if you're building a peaker, you're not building it for baseload, and if you're building a solar farm, you're not building for baseload, so these are different pieces of pie that interact with each other and give you an overall system that meets customer needs. With the addition of storage, you add flexibility to that intermittent resource that we have today, but regardless of the storage component, there's still a role that solar plays that's -- you know, produces the value to the system.

COMMISSIONER HAMILTON: Thank you very much. That was an excellent presentation.

Appreciate it.

MR. LEVITAS: I was just going to say that, I don't have a citation for you, but I did read something in the trade press in the last month, I'd say, that said the cost of solar plus storage is pretty close already to being able to displace gas peaking plants, and this was an energy trade magazine that was suggesting we're not going to see gas peaking plants built very much more in the future.

COMMISSIONER HAMILTON: Thank you very much. I appreciate the presentation. It was excellent.

MR. DAVIS: Thank you, Commissioner.

VICE CHAIRMAN ELAM: Commissioner Ervin?

COMMISSIONER ERVIN: Ron, I know we're talking about solar today, but the advances in battery technology, is it safe to assume we'll also benefit wind --

DR. DIFELICE: That's correct.

COMMISSIONER ERVIN: -- in the same way?

DR. DIFELICE: Exactly, yeah.

COMMISSIONER ERVIN: And make it a more cost-effective option?

DR. DIFELICE: In some markets like

Texas, you may know that the value of electricity goes negative when there's too much wind on the grid, and energy storage can certainly solve that problem for that electricity for later and deploy it when needed.

COMMISSIONER ERVIN: Thank you.

MR. DAVIS: And -- and just speaking, Commissioner Ervin, to the slide that Steve put up related to Colorado and Xcel's RFP last year -- all-source bid, they had a 450 megawatt capacity need and were fully anticipating that natural gas would come in lowest, and it was actually wind, solar, plus storage. So you are seeing storage show up in that mix with both wind and solar today and out-competing other resources.

COMMISSIONER ERVIN: I think I saw in the the Washington Post this morning that the current administration is looking favorably on wind, and they're actually talking to California about coordinating, you know, floating wind turbines so -- because the shelf is much deeper than it is on the East Coast. But I thought it was interesting -- that collaboration, at least. We haven't seen that in some other areas.

MR. DAVIS: And we -- we do have that offshore resource here in South Carolina. I assume at some point in the future it will enter into these conversations, but, for now, we've got sunshine that's ready.

COMMISSIONER ERVIN: Well, I found it very informative and an excellent presentation. I appreciate all of you attending today.

MR. DAVIS: Thank you.

VICE CHAIRMAN ELAM: Well, if there are no more, I have a couple, and I'll just throw the questions out and you -- you can choose who answers them. I believe y'all stated that most of the PPAs in South Carolina are in SCE&G territory. Is there a particular reason for that?

MR. DAVIS: I think the solar industry has found moving through the interconnection queue and the availability of contract length that's financeable has been available in SC&EG territory, and so it's driven that growth.

VICE CHAIRMAN ELAM: Okay. Now,

concerning the length of contracts -- you were asked about that -- is there a contract length that's set forth in the North Carolina legislation or the North Carolina Commission ordered?

MR. LEVITAS: Yes, sir. It's for the -- so we have a standard offer program for the smaller QFs, which was recently downsized to 1 megawatt. That is a 10-year PPA down from 15 where it had been for many years. For non-standard-offer projects, anything over 1 megawatt, it's a 5-year PPA term. And, as I mentioned, I was deeply involved in that legislation, and that 5-year number was not settled at through a process of trying to figure out what would work; it was through a process of trying to figure out would not work.

MR. DAVIS: Steve, what's the contract length for CPRE projects?

MR. LEVITAS: Yeah, so at the same time that the -- that these changes were made to migrate the state from PURPA implementation to competitive solicitation, the competitive solicitation program that has been put in place to supplant PURPA, if you will, provides for 20-year PPAs.

VICE CHAIRMAN ELAM: Okay. Just so I can understand, you said you were involved in that legislation; I take it you don't agree with everything that came out of it.

MR. LEVITAS: Well, I was -- no, we effected it in -- in the back-and-forth of the legislative process, we reached a negotiated agreement with the utilities. The things that were important to our side -- one of the things that happened was -- that -- that was very important to that deal getting done was grandfathering of a significant portion of the existing queue at the existing PURPA rates, so any time you're going to transition from one regime to another, you've got the issue: What do we do about the people who were in the middle of trying to get business done under the old regime? So a key part of that legislation that led to our willingness to support some of the changes was that grandfathering. In addition, I mentioned the 2660 megawatts of commitment to new renewables procurement, most of which will be solar, as well as a 600 megawatt, what we call a "Green Source Advantage Program," which is that program I alluded to in the legislation I worked on here in South Carolina, to try to give access for the commercial industrial customer. So, in total, we had 3260 megawatts of new solar procurement committed to in legislation, and that is, as far as I know, almost unheard of as a legislative commitment in the country. And so in exchange for both the grandfathering of a significant quantity of existing projects, a very large commitment to new renewables procurement, the solar industry in North Carolina was willing to migrate away from a pure PURPA regime and accept a term which, yes, we didn't like it -- we didn't like it going in, but we agreed to it as part of a comprehensive negotiation.

VICE CHAIRMAN ELAM: Okay. Was the grandfathering effective on the date of the effective date of the act, or was that the issue date?

MR. LEVITAS: The projects -- well, since I thought about this -- but it was projects had to have formed what's -- made the --

determined in PURPA -- a legally enforceable obligation prior to a date certain that preceded the act. I believe that date was November 15, 2016. So any projects that had effectively communicated to the utility their commitment to sell their output by that date retained their eligibility for the old rates under PURPA.

VICE CHAIRMAN ELAM: Okay. It didn't create some -- at some future date where you would have some sort of rush on the queue?

MR. LEVITAS: No.

VICE CHAIRMAN ELAM: Okay.

MR. LEVITAS: And it would -- all of the projects that were grandfathered had taken the necessary steps prior to the effective date of the legislation to become grandfathered.

VICE CHAIRMAN ELAM: Talking about lengths of contracts, is that in any way, in your thinking, tied to the useful life of a solar panel?

MR. LEVITAS: Well, we have seen as a industry norm -- unlike utility assets which typically do seek to obtain cost recovery over the full life -- useful life of the asset, we have not had that expectation because the useful life of our solar assets could be 35 years or longer. And that has not been a market standard to do 35-year PPAs, so we do have some risk, if you will, as to what the contract terms, pricing, and contract length will be after an initial contract term. But, generally, what we've experienced is that, on the strength of a reasonable initial contract term, that we can finance these projects and that we and our investors and financing parties are willing to take risks with respect to what happens after the term of that initial PPA.

VICE CHAIRMAN ELAM: Does that element of risk include, just, technological advances to the point where panels are a lot more efficient and producing a lot more, more cheaply?

MR. LEVITAS: Well, as long as PURPA is in place, the risk is somewhat mitigated because we do have a federal program that requires the utilities to buy our offtake.

We have that regulatory risk that that environment may change. So I don't think --

if PURPA were to remain as is, then there is less risk because those projects would be in place and would have rights under federal law to sell their output under a new contract. I think it's a bit more interesting in the competitive solicitation environment. I mentioned the 20-year contract term under the North Carolina program, which, by the way, the utility has a right to participate in, so they face the same risk calculation that we do. And so, it's unclear what's going to happen at the end of the 20 years of these projects that may get -- that will get selected in the competitive process, but I assume there will be a future competitive process after 20 years, and they'll -- and, to your point, Commissioner Elam, either they'll be successful in competing at that future point in time, or they may be overtaken by new technology and not be successful.

VICE CHAIRMAN ELAM: Final thing, you talked about various states having competitive generation for decades, and you said you weren't asking for that here. Do solar companies, such as the ones you deal with, do better in competitive generation states than they do in vertically integrated states?

MR. LEVITAS: Well, we certainly have more readily available market access in that we can readily sell our output without having to jump through some of the hoops and deal with some of the legal battles that we face in regulated markets. And I touched on the difference between the deregulated generation markets and then the wholesale markets that are more fluid and open, as well. Those are a little more complicated. The larger facilities have better access to sell into those wholesale markets; smaller distribution-connected resources don't have much opportunity to participate. And FERC has not recognized a PURPA exemption for facilities 20 megawatts and under in organized wholesale markets. So I think the answer is, yes, but as I said, we're not trying to seek that outcome or a particular outcome. The overarching goal that we have is to be able to access the market, place downward competitive pressure on pricing to the benefit of consumers, and I tried to lay out a couple of ways that we might get there.

VICE CHAIRMAN ELAM: Okay. That's all I have. Is there anything else from the commissioners?

COMMISSIONER ERVIN: I was told recently, Steve, that some of the proposals have been waiting in a queue for over two years with Duke. And I'm just curious, do you have -- since you're from, or familiar with, North Carolina -- how do you explain that?

MR. LEVITAS: Well, we have had prior presentations -- I think, prior to the time that you were seated on the Commission, on, specifically on the subject of interconnection, and I want to be mindful of my obligation not to talk about particular utility rates.

COMMISSIONER ERVIN: Right. And I don't want to single them out. But, just hypothetically speaking, why would it take an investor-owned utility that long to act on a queue?

MR. LEVITAS: Well, I think -- and it's not just here; it's not just one utility. But we see problems all over the country with interconnection, and I have been -- and I've said this publicly -- I've been sympathetic to a point with the utilities, recognizing that they've seen a tremendous influx from new generations, particularly renewable generation projects, that place demands on their resources. It takes time to study, time and cost to study these projects, and, of course, to build the facilities. But, that said, the rate of progress, particularly here in South Carolina, has been just absolutely unacceptable, if you just look at the time that projects are in the queue, the limited number that have made it all the way through and been interconnected, and this is true in North Carolina, as well. And I think, just to be honest about it, a sort of battlefront is we see from the utilities a lot of claims about technical standards and considerations with respect to interconnection. And they, of course, have a job to do to ensure system reliability. And, you know, I generally have high regard for the work that they do in that area, but frankly, we have seen one claimed technical screen after another, and ones that we don't believe are -- actually present problems that can't be overcome. And I just think, given the huge benefits to ratepayers, the huge demand for renewable energy and the benefits that it provides to the system, we've got a lot of smart folks out there in the utility industry, and I'd like to see more proactive, creative, aggressive efforts to solve whatever problems there may be and get these projects interconnected, rather than every time we turn around having some new obstacle thrown up in our path.

COMMISSIONER ERVIN: And that was some of the impetus for the new legislation; is that right? Because those that qualify under the new legislation can kind of jump the queue?

MR. LEVITAS: Are you talking about the North Carolina legislation?

COMMISSINER ERVIN: Yes, sir.

MR. LEVITAS: The legislation didn't speak specifically to that, but the regulatory proceedings that have followed on the legislation have created a pathway to expedite the interconnection of projects that are selected in the competitive process.

COMMISSIONER ERVIN: And that takes into consideration some of the utilities' concerns about location and need and accessibility?

MR. LEVITAS: Well, I think that's right. And I didn't touch on that at any detail, but I do think one, you know, potential concern/legitimate concern, about PURPA is that if you have a very high degree of PURPA penetration, you do have the potential, because one thing that PURPA allows is that we cite facilities wherever we may choose to cite them. And we recognize that that can present challenges, that you may have facilities cited that are remote from load or that present other operational challenges. I think the best way to address that is through the pricing mechanism, and I'm supportive of the idea that you shouldn't pay the price, same price, to a qualifying facility that is not located, effectively, relative to load. And you see this in locational marginal pricing in the organized wholesale markets. You don't have a uniform price everywhere. There's a recognition of supply and demand and where that supply is most needed.

VICE CHAIRMAN ELAM: Okay. If there is nothing further -- Mr. Whitt, anything further for you?

Thank you, gentlemen. I appreciate the presentation.

MR. DAVIS: Thank you, Commissioners, for your attention.

MR. WHITT: The only thing to add is we want to thank you, Mr. Vice Chairman, the Commissioners, and Mr. Melchers, and your staff for putting this together, and we appreciate the opportunity to appear in front of you. Thank you.

VICE CHAIRMAN ELAM: Thank you. Mr. Nelson? Anything else? Anything you need help getting anything?

MR. NELSON: I'll have a conversation with Mr. Whitt when we're done, but I'm fine. Thank you, Mr. Vice Chairman.

VICE CHAIRMAN ELAM: Okay. Appearing everything has been said that needs to be said, we're adjourned.

(WHEREUPON, at 3:08 p.m. the proceedings in the above-entitled matter were adjourned.)

(*This transcript may contain quoted material. Such material is reproduced as read or quoted by the speaker.)

(**Certificate accompanies sealed original only.)